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FLEXIBLE ELECTRICITY MARKETS FOR A DECARBONISED ENERGY SYSTEM

Klaus Skytte, Claire Bergaentzlé, Jonas Khubute Sekamane and Jonas Katz

Introduction

Reaching the European decarbonisation objectives will require a higher contribution of electricity generation from variable renewable energies, as well as the electrification of other sectors such as heat, transport, and gas. Future decarbonised systems will therefore impose new challenges in terms of flexibility, but they also will provide access to new, more-flexible solutions, provided the right market design is put in place to facilitate them.

Existing markets designs, with a few minor adjustments, could, in most cases, provide the needed flexibility to ensure optimal short-term dispatch, reliability and long-term capacity adequacy. However, in high-residual load periods, there is a need for better scarcity pricing to solve the missing money problem.

In this paper, we combine a premium that strengthens scarcity prices and a mechanism that significantly mitigates the risk on the investment side, while effectively sharing it with consumers. Our vision for a future electricity market uses a combination of plausible approaches to support flexibility. It aims to address the framework conditions necessary to activate flexible resources based on: i) renewable energy-based wholesale market designs; ii) cross-sectoral coupling; and iii) innovative scarcity pricing and risk reductions through reliability options.

Our proposed vision improves the design of electricity markets and establishes new sets of frameworks that support flexibility as the core element in a decarbonised energy system with a large share of variable renewable energies.

The future power market

European energy markets are going through a green transition toward a future with a decarbonised energy system. Centralised, fossil-intensive electricity generation is being replaced by decentralised renewable energy. A large share of variable renewable energy (VRE) sources, especially wind and solar, will be deployed, in addition to other traditional storable renewable energy sources, such as biomass and hydropower. By nature, the temporal supply of VRE is highly variable because it depends on weather conditions, uncertainty due to forecasting errors and location specificities, as the primary energy source cannot be transported, like coal or biomass (Borenstein, 2012; Hirth et al., 2015). Such properties point to major VRE integration and flexibility challenges for the future energy system. Simultaneously, the traditional and flexible fast-responding, fossil-based peak-generators are being phased out, increasing flexibility challenges.

Future European energy systems should be consistent with the threefold targets set to improve competition, reliability, and sustainability (see Figure 1). Existing power markets were created before or simultaneously with setting up the EU goal of developing an Internal Energy Market, which facilitate low consumer prices through competition and reliability by matching electricity demand and supply (EU Directive 2009/72/EC). The market design that emerged over the years might have to be adapted according to the green transition such that it enables necessary short- and long-term flexibility in the system.

The future market design should be based not on the perspectives of the traditional electricity sector, but rather on an integrated decarbonised energy system in which electricity becomes a cornerstone in the sustainable energy transition for other energy sectors – such as heat and gas – as well as for transport and other service sectors with a large share of electrification (Skytte, Pizarro and Karlsson, 2017b). The progressive coupling between the electricity sector and the other sectors will increase the volumes traded on the electricity market, as well as competition that ultimately will benefit consumers. If sector coupling is done in a 'smart' way, it also may increase the flexibility of the system – especially on the demand side – by unleashing the potential for electrification via flexible load units with ramping capabilities such as electric boilers in heating systems, electrolysers in power-to-gas or smart charging of electric vehicles (Skytte et al., 2017a; Ropenus and Skytte, 2007).

Though increased flexibility, thanks to cross-sectoral coupling, will play a key role in reaching decarbonisation targets, the right market design will be required to ensure a high level of short-term reliability and long-term capacity adequacy at the lowest cost.

Price setting in energy markets

In most of the present power markets, the wholesale electricity price is determined according to the marginal cost of the last dispatched generation plant (see left panel in Figure 2). It has been shown to be a very effective market design that so far has entailed energy prices that both support optimal dispatch/short-term reliability (Skytte and Grohnheit, 2017) and optimal investment/long-term capacity adequacy (Biggar and Hesamzadeh, 2014; Green, 2006; Schweppe et al., 1988). Although only energy is traded on the power markets, flexibility is valued, as demand and generation units with flexible ramping capabilities can make a better business case in volatile markets, compared with slow ramping units.

The success of the existing design also must be seen in the context of a large deployment of renewable energy-based capacity. This capacity has received additional financial support from outside the market, resulting in overcapacity on the supply side. Therefore, there is presently limited need for additional investment in conventional generation capacity. Nonetheless, with increased demand from sector coupling and the phasing out of fossil-based generation, additional generation capacity will be needed in the future. Simultaneously, support for renewables will be phased out in accordance with the maturing of technologies and it can be expected that future deployment will be mainly market-based (Skytte, 2000; Skytte, 2006; van Kuik et al., 2016).

In a period with scarce supply – e.g., when the residual demand is large due to little wind or solar production and with simultaneously high demand – the price in the power market is likely to be set by the marginal consumer benefit (see right panel in Figure 2). This is called *scarcity pricing*. Scarcity is a necessary (although not a sufficient) condition for a well-functioning market and optimal allocation of resources – often referred to as the first principle of micro-economics. The main dilemma in the power market is that the current demand side is relatively price-inelastic (the demand

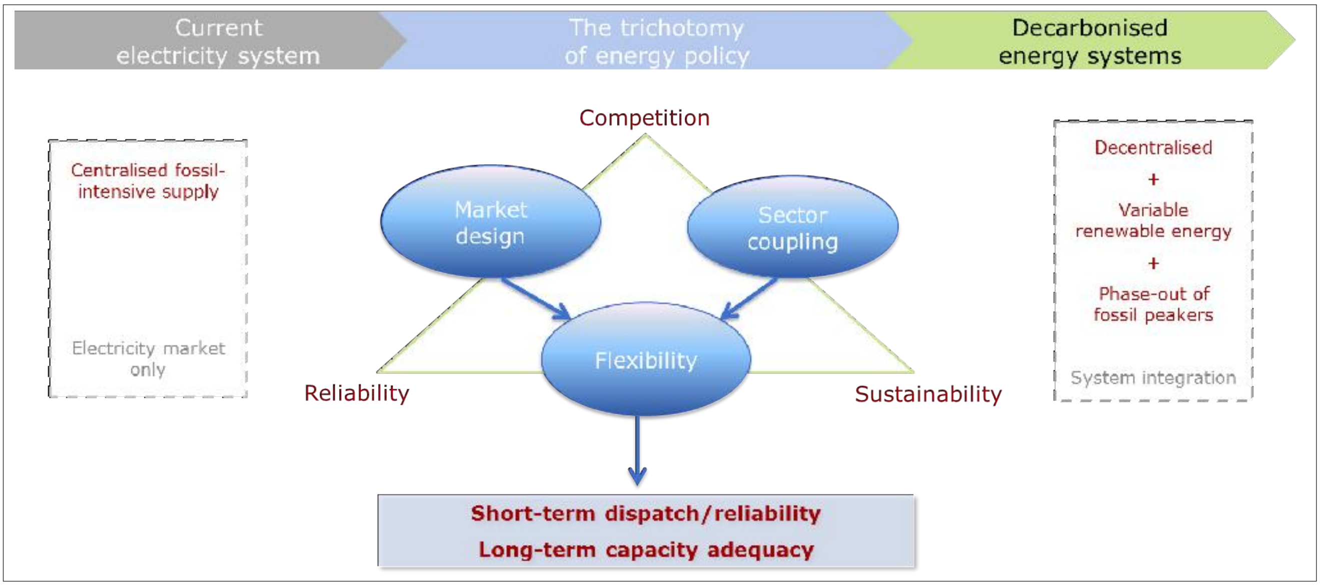

Figure 1: Goals and framework of the future energy market

curve D in Figure 2 is almost vertical), which implies that it is hard to determine a sufficient scarcity price. We call this missing flexibility on the consumer side the *missing consumer problem,* which may imply that the price does not reflect the marginal consumer benefit or, at worst, that an equilibrium between demand and supply cannot be found. Within energy economics, the marginal consumer benefit in scarcity periods is often estimated as the value of lost load (VOLL) for marginal consumers, i.e., the amount they are willing to pay to avoid a disruption in their electricity supply.

Electrification and sector coupling will increase electricity demand and might also increase the availability of flexible load units with ramping capabilities – and, thus, the marginal price elasticity needed to solve the missing consumer problem. However, the problem of determining an efficient level of scarcity pricing also affects the supply side. If the estimated VOLL is set too low, investments in new capacity may be withdrawn, leaving the market unable to ensure long-term adequacy. Lower prices in the power market increase the need for higher scarcity prices to ensure investment, as a low price level implies that a large share of the revenue to cover the investment costs must come from scarcity periods, when the price is higher than the marginal cost of the last generating unit (right panel in Figure 2).

VRE, such as wind and solar, will be the main suppliers of electricity in the future, as more controllable renewable energy-based technologies such as hydropower and biomass involve more limited resources or are subject to restrictions on further deployment. The dominance of low marginal cost VRE technologies implies low average prices on the wholesale markets (Skytte and Grohnheit, 2017). As mentioned above, a low price level, combined with insufficient scarcity prices, could imply that potential investments in new capacity are withdrawn (Joskow, 2008; Joskow and Tirole, 2007). This is called the *missing money problem*, i.e., the revenues in the energy market will not cover the needed investments in new capacity, thereby failing to ensure the long-term adequacy of the system. In addition, price caps have been implemented in many markets to protect consumers from high peak prices that might result from market forces. Such price caps will limit scarcity prices and contribute to the missing money problem.

Need for re-design

The existing market design and its marginal pricing, with a few minor adjustments, works in most cases. However, in the event of scarcity, there is a need for better scarcity pricing to solve the missing consumer and missing money problems.

The general problem is that market imperfections exist in the power market (Skytte, 1999). In addition, the uncertainty of future prices increases risks for investors and may, as a consequence, hinder new investments. Better risk-hedging possibilities for investors, in addition to the existing forward and other financial markets, may be required.

Therefore, we do not support capacity mechanisms just to have enough capacity available, but rather to fix

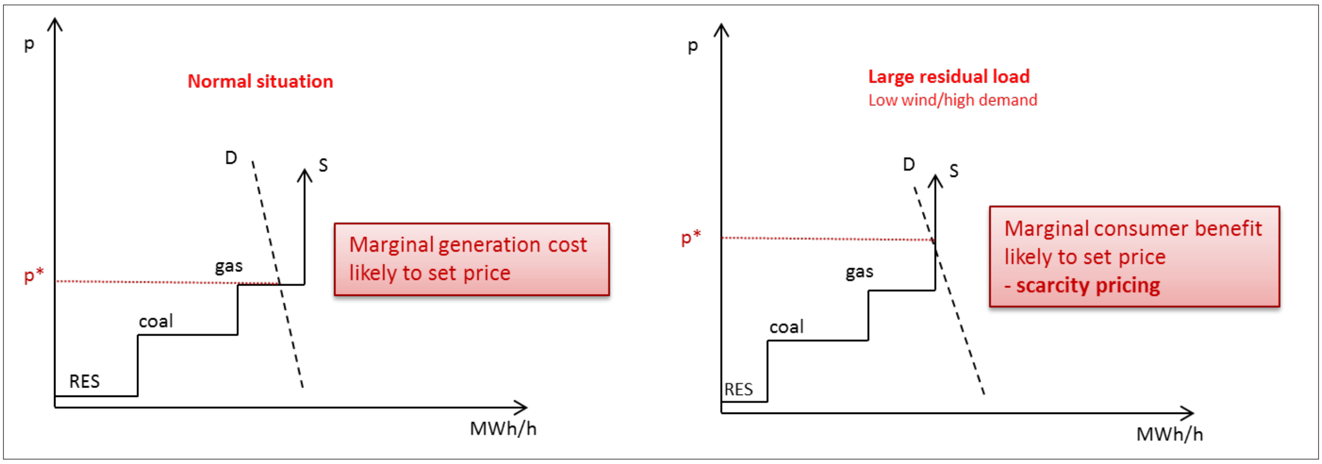

Figure 2: Price setting on the power market (RES = renewable energy sources)

the existing scarcity-pricing problem in the energy-only market – with as little interference from market mechanisms as possible – and to reduce investment risk.

In this paper, we propose a combination consisting of a premium that enforces scarcity prices and a mechanism that, to a certain extent, mitigates the risk on the investor side and effectively shares it with consumers. The constructed mechanisms draw on Hogan (2013) and Cramton et al. (2013). We introduce a premium in scarcity periods, and we also allow generators to sell *reliability options* that reduce their risk of investment. These two instruments work concurrently, with the premium increasing the revenue of generators, while the reliability options allow generators to swap revenue from the few high-price periods with a stable, risk-free payment. The following subsections describe the premium and reliability options in turn.

Ensuring scarcity prices with premiums

One should seek a re-design of the energy markets that respects the first principle of economics in terms of scarcity. One way to do this is to strengthen scarcity prices through a premium based on the VOLL and the loss of load probability (LOLP).

At times of high demand in the energy spot market, there will most often be sufficient capacity to clear the market because the system typically will contain a certain capacity margin. In this situation, there will be no scarcity and prices will stay at moderate levels, presumably at the short-run marginal cost of the most expensive unit in the market (left panel in Figure 2). The high demand for capacity may, however, create a tense situation regarding operating reserves that are retained at any given time to deal with unexpected events, such as a sudden increase in electricity demand or the loss of a generator or transmission line. Typically, the system operator would define an inelastic demand for operating reserves. When the reserve market does not clear itself, the only solution might be to shed load or to use other out-of-market transactions, both of which will not be reflected in the operating reserve or the spot-market prices. By defining a proper demand curve, such issues could be prevented and scarcity signals could be sent to all market participants.

We propose using a downward-sloping, *operating-reserve demand curve* (Figure 3), which is determined by the expected value of lost load (i.e., the product of loss of load probability and value of lost load; LOLP by VOLL) at any given time (Hogan, 2013). The more capacity available for operating reserves, the lower the LOLP, yielding the slope in the demand for reserves. This translates into an implicit premium (“price adder”) on top of the electricity price in scarcity periods (right illustration in Figure 3). The underlying assumption is that generators will be able to either supply energy to the spot market or stay available for reserves. With rising demand in the spot market, the available capacity for reserves will be smaller. Due to the shape of the operating reserve-demand curve, this may result in sharply rising reserve prices. Therefore, in scarcity periods, when the probability of loss of load is high,

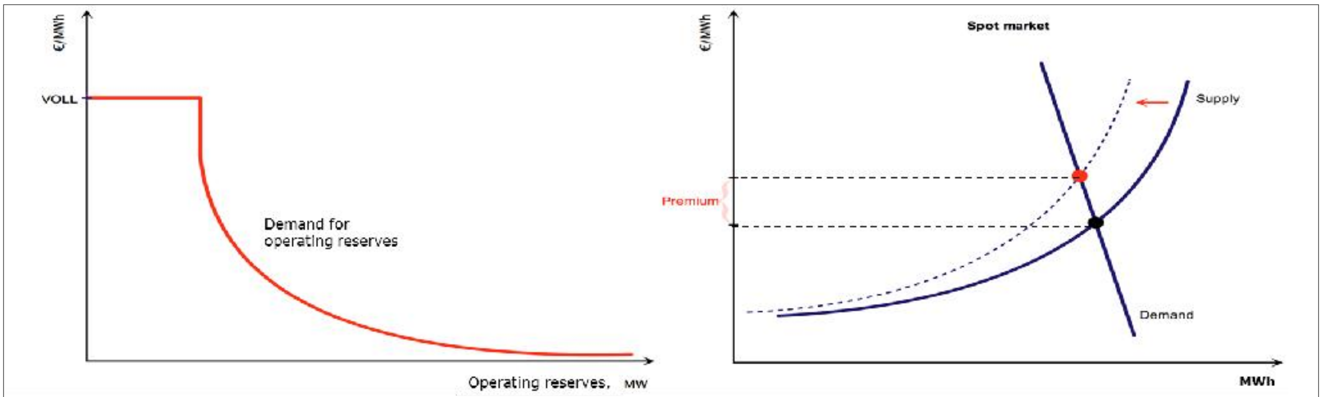

Figure 3: The downward-sloping Operating Reserve-Demand Curve (left figure) as a basis for a scarcity premium on energy prices (right figure)

the implicit premium is correspondingly high, while in other periods, in which the probability is negligible, the premium is close to zero.

The resulting premiums provide generators with additional revenue, improving the incentive to invest in new capacity (mitigating the missing money problem) and at the same time providing a stronger price signal to the demand side, to which the consumers can react.

However, the scarcity premium does not remove investor risk due to the uncertainty of future prices. Therefore, it is not certain whether the mechanism ensures sufficient capacity in practice. It could still be an important adjustment to the existing operating reserve markets, as the short-term price signals become more precise. While the profitability of investments would be improved, the cash-flow timing and investment risk are not addressed. We introduce *reliability options* to bridge the remaining gap to achieve adequate investments.

Reliability options

Reliability options allow generators to swap revenue from a few scarcity periods with a stable, risk-free payment. We propose that the system operator organises annual auctions to buy a predetermined number of reliability options (corresponding to the expected future capacity needs) with a predetermined strike price and a time horizon that allows for the introduction of new capacity. When a generator sells a reliability option, it will still receive the spot price for the energy it produces, but only in those hours when the spot price is lower than the strike price (see Figure 4). In all other hours (scarcity periods), it receives the strike price for the energy it produces. Note that in our case, the spot price includes the implicit premium stemming from the demand for operating reserves. In addition, the generator earns the selling price of the reliability options. Thus, the generator swaps the revenue it would have earned during the infrequent high price periods (i.e., above strike price) with a stable and risk-free payment for the reliability option. While the option payments compensate for the price risk during scarcity periods, market participants will still be fully exposed to price variations below the strike price. Standard forward contracts might, therefore, be used as a supplement to manage price risk below the strike price.

The advantage of reliability options is that they maintain the incentive for generators to produce electricity in scarcity periods, as the system operator sets the strike price such that it is above the marginal cost of the most expensive generation unit (resembling the scarcity situation in the right panel of Figure 2). Thus, any generator will earn a positive profit from producing electricity at the strike price. Just as under the option contract, a generator is obliged to pay the difference between spot and strike price whenever the strike price is exceeded, not producing in such an event will produce significant losses – a strong incentive to provide full capacity during scarcity events.

System reliability can, to a certain degree, be considered a public good. Improving reliability benefits all consumers because load curtailment at the individual level is currently not widely available. Thus, consumers have an incentive to free-ride and let others pay for improved system reliability. For this reason, we propose that system operators purchase reliability options on behalf of all consumers in a centralised auction and distribute the cost according to their respective shares of the load. In exchange, consumers receive a hedge against high electricity prices and inadequate capacity. This hedge against price peaks will have the same objective as present price caps which most likely

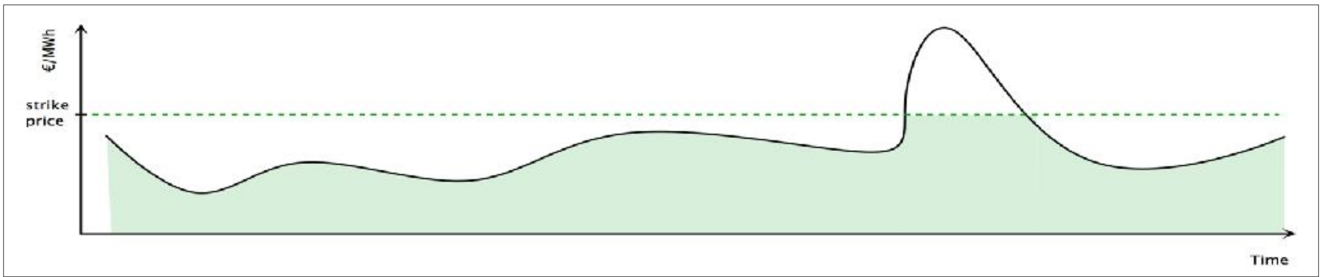

Figure 4: Reliability options and the spot and strike prices

will be removed in the future power market in order to allow for scarcity prices. Finally, from the point in time when the reliability option is sold until the contract takes effect, a few years will pass. This will allow new capacity to compete with existing capacity, as there will be time to construct new capacity between the auction and the delivery period.

If load curtailment at the individual level becomes widely available, the centralised auction can be replaced with a market for reliability options, in which consumers can decide whether to buy or not. If they decide not to purchase, they will accept the risk being curtailed in case of scarcity.

Discussion

Why choose our proposed scarcity premium and reliability options instead of traditional capacity-remuneration mechanisms? Different capacity-remuneration mechanisms (Table 1) are often mentioned during discussions about adequacy concerns and as a means to minimise investor risk. However, conventional strategic reserves and capacity payments or markets (capacity obligations or auctions) exhibit some deficiencies that regulators prefer to avoid (Finon and Pignon, 2008; Traber, 2017). Strategic reserves, for instance, remunerate capacity, so that it remains available and can be dispatched in times of scarcity. Typically, strategic reserves are mainly targeted at existing capacity and do not have a direct impact on new investments. As a long-term mechanism to ensure adequacy, they are, thus, not applicable. Among other capacity-remuneration mechanisms, reliability options have an advantage in that contracted capacity provides a distinct incentive to be available during periods of scarcity, while it does not profit from extreme energy prices directly (Cramton et al., 2013). Therefore, potential issues with market power in the energy spot market can be avoided to some extent.

Texas has implemented a variant of scarcity prices based on the operating reserve demand curve (ERCOT 2014), while a variant of reliability options has been implemented in the Colombian electricity market and in New England (Ausubel and Cramton 2010). However, to our knowledge, no one has combined the two approaches yet.

Throughout this paper, we assume a future in which large-scale electricity storage remains prohibitively costly, and commercial and residential demand-side response is limited. It is worth noting that the proposed mechanism can fall back to an energy-only market if a different future materialises. That is, if the loss of load probability is zero, the premium vanishes. Similarly, if storage or demand-side response completely eliminates price spikes and increases the average spot price, reliability options would lose their value as well. Thus, the proposed mechanism is not path-dependent, but easily reversible.

In theory, neither the premium nor the reliability options distort short-term dispatch incentives. However, further research is needed to determine how forecast errors by the system operator affect the market, i.e., forecast errors in the expected value of lost load, expected future capacity need, or marginal cost of the most-expensive generation unit. Further research is also needed to determine the exact interaction between the two mechanisms.

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Volume-Based				Price-Based
Targeted	Market-Wide			
Strategic reserves	Capacity obligation	Capacity auction	Reliability option	Capacity payment

Table 1: Capacity-Remuneration Mechanisms

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